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BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company Proposing Cost of Service and Rates for Gas Transmission and Storage Services for the Period 2015-2017 (U39G).	Application 13-12-012 (Filed December 19, 2013)
And Related Matter.	Investigation 14-06-016

NOTICE OF EX PARTE COMMUNICATION
BY COMMERCIAL ENERGY OF CALIFORNIA

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Dated: June 16, 2016

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OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company Proposing Cost of Service and Rates for Gas Transmission and Storage Services for the Period 2015-2017 (U39G).	Application 13-12-012 (Filed December 19, 2013)
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Pursuant to Rule 8.3 of the Commission's Rules of Practice and Procedure, Commercial Energy of California ("Commercial Energy") submits this Notice of an Ex Parte Communication.

On Monday, June 13, 2016 at 1:00 pam Michael Day, counsel for Commercial Energy, and Ron Perry, President and CEO of Commercial Energy, met with Ken Koss, advisor to CPUC President Michael Picker at the Commission's offices in San Francisco. The meeting was initiated by Mr. Day and lasted approximately 30 minutes. During the meeting, Mr. Day and Mr. Perry addressed four issues from the PG&E GT&S Proposed Decision ("PD") affecting Core Transport Agents ("CTAs"). Mr. Day explained Commercial Energy's support for the PD's retention of the Peak Month allocation method, and its relation to the Commercial Energy Peak Day pipeline cost allocation proposal. Mr. Day also described evidence from PG&E testimony and comments from a TURN brief in the case that supported Commercial Energy's contention that core peak demand is served by additional pipeline capacity. The record evidence confirmed that it is not true that core peak demand is served solely by storage withdrawals. Mr. Day and Mr. Perry also indicated that the PD should be revised to mandate that PG&E propose improvements to its core load forecasting model using Smart Meter data and comments from CTAs. The Commercial Energy representatives also urged that CTAs whose customers have already signed written agreements or forms authorizing access to customer billing and payment information should be exempted from the PD's requirement to obtain the customers' signatures on an additional authorization form. Finally, Mr. Day explained why the transition period for reducing the CTAs' assigned storage capacity from PG&E should begin on April 1, 2017, the beginning of next the gas year for storage injection. Mr. Perry and Mr. Day explained that while Commercial Energy originally recommended a nine year transition for both pipeline capacity and storage capacity, the four year transition period for storage recommended by CTAC is reasonable and should be adopted. A three page outline of the Commercial Energy recommendations and two excerpts from the record (a portion of PG&E testimony from Exhibit CTAC-6 and an excerpt from the TURN Opening Brief in this case) were used in this ex parte communication, and are attached to this document.

For a copy of this notice please contact Ms. Wendy Peña at 415-392-7900 or wpena@goodinmacbride.com.

Respectfully submitted June 16, 2016 at San Francisco, California.

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By *_/s/ Michael B. Day_*
Michael B. Day

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3418/004/X182473.v1

ATTACHMENT

PG&E 2015 GT&S PROCEEDING
A.13-12-012; I.14-06-016
COMMERCIAL ENERGY SUMMARY OF CTA ISSUES

PIPELINE COST ALLOCATION METHODOLOGY

PG&E witness Elmore proposed to change the mandatory interstate and intrastate pipeline cost allocation from a January Peak Month criteria to a Seasonal (really an Annual) Load criteria without discussing the implications with any of the Core Transport Agents, or CTAs. Commercial Energy (CE) quantified that applying this method to both inter- and intrastate transmission would result in an $11 million cost shift to the CTAs as a group (a 42% increase for the class). All CTAs *except one* would see cost increases, with over a third receiving increases of between 57% to 126%.

In response, CE advocated for an allocation based on cost causation principles, using a Peak Day criteria. CE's logic is that pipeline capacity is acquired on an annual basis so that the utility holds enough winter capacity to meet its core Peak Day needs. The record in this case is full of evidence demonstrating this.

For example, CTAC introduced the testimony of PG&E in the core gas capacity planning case (Ex. CTAC-6, PG&E Direct Testimony in A.13-06-011.) PG&E's witness, Karen Lang, explained , "While annual constant contract volumes may sometimes be the only form of interstate capacity that pipeline companies are willing to offer, such contracts result in *EXCESS CAPACITY* during May through September." (Ex. CTAC-6, p. 5. (emphasis added)) No party provided any evidence to dispute this. PG&E's own testimony also confirmed that PG&E has also purchased higher volumes of interstate capacity in the five peak demand winter months to meet peak core needs. (*Id.*, p. 7.)

On a statewide basis, the total interstate capacity interconnected to the utilities to ensure sufficient ability to move gas for peak day core demand provides even greater excess capacity. PG&E's testimony confirmed that "the current interstate pipeline capacity connected to California, 10.5 Bcf/d, is far greater than both the projected state peak load of 9.4 Bcf/d and annual average loads of 6.1 Bcf." (*Id.* p. 15.) *The effect of this enormous baseload capacity to meet core winter peak load is a 44% over-building of capacity*. This is calculated by dividing the overcapacity by the needed winter capacity, (10.5-6.1)/10.5Bcf = 44%). Clearly, PG&E, like other utilities, relies upon substantial excess quantities of interstate pipeline capacity to meet peak core needs (and maintains matching intrastate backbone capacity to carry the gas to market).

In contrast, SPURR and TURN contend that transmission capacity is only purchased to meet annual load and that core peak demand is met entirely with storage. TURN attorney/witness

Hawiger claimed as much in the recent All Party Meeting in this case. However, this position is contradicted not just by the PG&E testimony quoted above, but by statements in TURN's Opening Brief. There TURN stated that "the data show that at least 58-75% of the pipeline cost is driven by the need to meet average day gas throughput, while only about *one-quarter to one-third of the pipeline cost is driven by the need to meet peak load*." (TURN Opening Brief, April 29, 2015, p. 209, (emphasis added).) While TURN's arithmetic is wrong (the correct range is 25% to 42% of pipeline costs related to peak load, not 25% to 33%), their statement is reasonably accurate. A large portion of the costs to build PG&E's pipeline system are related to serving peak core load, and that is why Commission precedent supports using peak load allocation factors in assigning these costs to customers. (See CE Opening Brief, pp. 37-39; CE Reply Brief, pp. 30-32.)

PG&E's own evidence, together with TURN's quantification, leave no doubt that the Proposed Decision (PD) was correct in deciding to retain the January peak month capacity factor rather than adopt PG&E's seasonal (annual) cost allocation, and was supported by adequate record evidence. PG&E both contracts for substantial additional interstate capacity to serve peak winter loads and builds its intrastate system to accommodate winter peak demand. As a class, CTAs serve customers with an overall flatter load profile and do not contribute nearly as much to winter peak demand as the residential core. There is no justification for loading extra pipeline costs on CTA customers as PG&E proposes.

ACCESS TO SMART METER DATA AND IMPROVED CORE LOAD FORECASTING

CE believed that the $3 billion investment the ratepayers made in Smart Meters over the past five years should enable the utilities to upgrade their information and improve core load forecasting. The PD correctly finds that PG&E should have sufficient accumulated Smart Meter data by now to make improvements to the Forecasting Model (CLFM). The PD also correctly finds that CTAs should be included in helping to improve the CLFM. But the PD fails to actually direct PG&E to make changes to the CLFM using Smart Meter data; it only encourages PG&E to consider doing so. PG&E must be directed to actually propose changes that use Smart Meter Data and reflect the input from CTAs.

CTA ACCESS TO CTA CUSTOMER BILLING AND PAYMENT INFORMATION

The PD acknowledged that CTAs truly are agents for their clients, and that PG&E is a billing agent for the CTAs who use consolidated billing. Therefore PG&E must reveal to the CTA the credit condition of the CTA's own customer. The decision also states that the form currently used to obtain consent for the disclosure must be updated. Unfortunately, the decision errs in requiring existing CTA-served clients to sign yet another authorization before such information is released. This is unnecessary and would functionally prevent CTAs from accessing this data.

Those CTAs (like Commercial Energy) whose customers have already signed a written contract with an explicit authorization for the CTA to access customer billing and payment data, or customers who have completed form 79-1095, should be exempt from the additional acknowledgment requirement. There is no need for a duplicative authorization.

TRANSITION TO INDEPENDENT CTA STORAGE PROCUREMENT

CE proposed an amortization period of nine years to free the CTAs from mandatory cost allocation of PG&E's uneconomic storage costs. CTAC has proposed a four year amortization beginning April 1, 2017. CE agrees that this is a reasonable timeframe, given that PG&E can simply transfer the excess storage to its market storage program, and other core customers need not bear any additional costs. In addition, CE recommends a slight modification to the transition period for the start of this program. The PD should be modified to start the transition at beginning of gas year, April 1, 2017 when the injection season begins. PG&E agreed with the April 1 start date.

THE IMPORTANCE OF CTA ISSUES IN THIS CASE

Commercial Energy and its over 3,000 business customers appreciate the time to share our views and help bring this case to its conclusion. A full 40% of all of PG&E's commercial customers take CTA service.

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OPENING BRIEF OF THE UTILITY REFORM NETWORK

Excerpt pp. 206-211

TURN
THE UTILITY REFORM NETWORK
Lower bills. Livable planet.

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April 29, 2015

measure for local transmission in 1992. Absent such evidence, the Commission should reject Mr. Beach's recommendation to shift $57 million to core customers.

17.2.2.4 The Evidence in This Proceeding Demonstrates That the Existing Cold Winter Month Marginal Demand Measure Actually Allocates Too Much of the Local Transmission Revenue Requirement to Core Customers

The data in this proceeding show that the marginal costs of new pipeline capacity are primarily caused by the need to transport the average daily amount of gas, not the peak day amount. PG&E explained in its rebuttal testimony that marginal pipeline costs are not driven by the need to serve peak day demand:

> PG&E's Local Transmission system is a shared resource between core and noncore to a far greater extent than is the case for PG&E's Distribution system, which has a spider-web of small pipes down every neighborhood street in the service territory serving practically only residential customers. To argue that the entire Local Transmission revenue requirement is caused by the incremental investment serving the peak design day compared to a flat daily demand is without merit.[709]
>
> That the long-adopted, state-wide CYPM method is a reasonable reflection of the costs imposed by core versus noncore customers for the shared resource of the Local Transmission system. While the peak day planning criteria may determine the size of the pipe necessary to meet core demand on a very cold day, the cost of meeting that demand does not increase proportionately to the change in the demand or the differential in demand between serving a perfectly flat load shape and serving an incremental demand that is peaky.[710]

PG&E's rebuttal testimony is supported by undisputed factual evidence concerning pipeline flow and pipeline costs. First, the capacity of a pipe increases much more rapidly than the size of a pipe, due to the fact that flow is proportional to the square of the pipe radius.[711]

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[709] Exh. PG&E-43, p. 17-17, lines 7-13.

[710] Exh. PG&E-43, p. 17-17, lines 17-24.

[711] 25 RT 3170 (PG&E/Christopher) and 27 RT 3644:14 – 3645:3 (Calpine-Indicated Shippers /Beach). Pipe "capacity" describes the amount of throughput (volume per time) that can flow at a given pressure differential.

PG&E's data show that, for example, a 50% increase in pipe diameter (from 16 to 24 inches) results in a 200% increase in pipe flow (from 3.7 to 11 MMcfh).[712] What this means is that if PG&E needs to increase throughput by 100% in a particular local transmission system in order to meet the CWD requirement for that local transmission area, it does not need to increase pipe diameter by 100% to meet the flow requirements.

Second, PG&E's pipeline installation costs do not increase linearly with the size of a pipe. Because certain costs are fixed and do not vary at all with pipe size, PG&E forecasts a unit cost for the vintage pipe replacement program that is almost uniform for all pipes less than 24 inches in diameter, and then almost doubles in a step function to a higher cost for larger pipes in congested areas.[713] For its pipe capacity program, PG&E provides illustrative costs that show a similar pattern, with slightly more granularity.[714]

These relationships between pipeline size, pipeline capacity and pipeline cost are summarized in Table 10, using data provided by PG&E. While TURN does not accept these specific pipeline unit cost estimates, especially for the large pipe diameters, TURN agrees with the general relationship between size, flow and cost shown in the following Table.

Table 11: Relationship Between Pipe Size, Flow and Cost[715]

Pipe Diameter	Flow (MMcfh)	Cost (Using Congested Category) ($/ft)
12	2.1	1000

[712] Exh. TURN-63.

[713] Exh. PG&E-05, p. WP 4A-722. TURN does not at all accept this cost estimate; however, TURN generally agrees that there may be some increase in costs between smaller and larger pipes, primarily due to larger materials and trenching costs.

[714] Exh. TURN-62 shows illustrative costs. PG&E's forecasts for capacity projects shows even less difference in cost versus pipe size, as discussed in Section 7.6.5.2.

[715] Data from Exhibits 62 and 63, PG&E Responses to TURN DR 051-01 and 02.

Pipe Diameter	Flow (MMcfh)	Cost (Using Congested Category) ($/ft)
16	3.7	1325
20	6.9	1325
24	11	2275
30	19.9	2275
34	27	2275

Mr. Beach's recommendation is based on the assumption that peak day load is the entire cost driver for PG&E's local transmission costs, thus "causing" the cost of the pipeline.[716] However, the data presented above demonstrate that even though CWD is the design criterion for pipe capacity, pipeline *costs* are not driven by peak day flow requirements. Rather, the majority of the costs for a new or replacement pipeline are driven by the need to provide a certain average amount of gas each and every day.

PG&E's data can be used to quantify the relative costs of building a pipeline sized to meet average day flow, versus the costs of building a pipeline sized to meet peak day flow. The average 2015 forecast gas flow on PG&E's system is 1957 MDth/d,[717] while the forecast CWD flow is 3550 MDth/d.[718] This means that if the local transmission system were sized to accommodate cold winter day flow, the system-wide average load factor would be 55%.[719] In other words, if there were only one hypothetical pipeline that had to meet the forecast flow

716 27 RT 3639:16-23 (Calpine-Indicated Shippers /Beach).

717 Exh. PG&E-01, Table 14-1, p. 14-3 (as modified in errata).

718 Exh. Calpine/Indicated Shippers-01, Attachments B, Response to DR-GTN-02-021.

719 See, for example, 27 RT 3641:5 – 3642:14 (Calpine-Indicated Shippers/Beach). This is a system-wide average number, and specific local transmission pipeline load factors will differ based on the relative proportion of weather-sensitive load on that segment.

requirements, PG&E would need to build a pipeline sufficient to carry 3550 MDth/d, but the average daily flow would be 1957 MDth/d, resulting in load factor of 55%.

PG&E's data presented in Table 11 above illustrate how these flow requirements determine pipe size. For example, if PG&E had to meet an average daily flow of 3.7 MMcf/d, it could build a 16-inch pipeline. However, if PG&E had to accommodate the same average flow but also meet a peak flow of 6.7 MMcf/d, it would have to build a 20-inch pipeline, resulting in a 55% load factor.[720] Similarly, to accommodate the same average flow but meet a peak load of 11.7 MMcf/d, PG&E would have to build a 24-inch pipeline, resulting in a load factor of 34%.

Furthermore, the cost data show that PG&E would actually not spend any more money to build the 20-inch pipeline than the 16-inch pipeline, since the unit cost of these two pipelines is forecast at $1,325 per foot for both pipe sizes. The cost of installing the 24-inch pipeline is 72% higher than the 16-inch pipeline. Indeed, for the relevant range of load factors, the data show that at least 58-75% of the pipeline cost is driven by the need to meet average day gas throughput, while only about one-quarter to one-third of the pipeline cost is driven by the need to meet peak load.

[720] The load factor is simply average flow divided by peak flow. (3.7/6.7 = .55) As explained during cross-examination of Mr. Beach, the load factor is calculated by dividing the capacities of each pipeline. See, 27 RT 3634:10 – 3648:11 (Calpine-Indicated Shippers/Beach).

Table 11: Comparison Pipe Throughput and Costs for Relevant Pipe Sizes

Pipe Diameters	Load Factor of Larger Pipe[721]	Cost Factor of Larger Pipe[722]
12 v. 24	0.19	0.44
16 v. 24	0.34	0.58
24 v. 30	**0.55**	**1.00**
12 v. 16	**0.57**	**0.75**
20 v. 24	**0.63**	**0.58**
20 v. 30	0.35	0.58

These data quantify what Mr. Beach succinctly described as the "economies of scale" present in gas pipeline construction:

> Q Okay. And how does the costs for new pipe or replacement pipe – how do they vary with the size of the pipe?
>
> A Well, I mean, I think that there are to some extent economies of scale in putting in natural gas pipelines so that a – a bigger pipeline will transport, you know, more gas per unit of cost than a smaller diameter pipeline.[723]

Mr. Beach's recognition of the economies of scale regarding unit costs undermines his conclusion that meeting "peak day load" is the primary driver of local transmission pipeline costs.

The Commission adopted the CYM marginal demand measure for allocating local transmission costs based at least in part on the notion that "the MDM should be somewhere

[721] This number is the load factor of the larger pipe if it carried the same average flow as the smaller pipe, but had a peak day flow equal to its entire capacity.

[722] This number is the ratio of the unit cost of the smaller pipe divided by the unit cost of the larger pipe. Based on the data in Exhibits 62 and 63, as shown in Tables 4 and 5.

[723] 27 RT 3637:11-19 (Calpine-Indicated Shippers/Beach).

between transmission and distribution."[724] In the LRMC decision the Commission accepted the use of capacity design criteria as reflecting marginal costs in the LRMC decision, stating that:

> The controlling planning criteria used by the utilities reflect the manner in which the utilities will incur costs in response to changes in demand for specific functional elements of their respective systems. Thus, parties' requests that we deviate from the utilities' planning criteria in favor of "flatter" allocation factors could result in adopting measures of cost responsibility which depart from accurate marginal costs.[725]

While PG&E has continued using the CYM as the local transmission allocator since the first Gas Accord, the data in this proceeding suggest that "flatter" allocation factors for local transmission costs may actually more accurately reflect marginal costs.[726] Given that the majority of pipeline costs appear to be driven by average flow requirements, using an allocator such as "peak and average" (load factor multiplied by average demand and one minus load factor multiplied by peak demand) or cold year average daily flow may more accurately reflect cost drivers.[727]

The Commission should thus 1) maintain the existing CYM allocation of local transmission costs for this rate case; and 2) order PG&E to provide an analysis in the next GT&S rate case demonstrating whether local transmission costs should be allocated more equitably by accounting for the actual relationships between pipeline capacity, throughput and costs.

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[724] D.92-12-058, 47 CPUC 2d 438, 455.

[725] D.92-12-058, 47 CPUC 2d 438, 454.

[726] The term "flatter" is a long-accepted method of describing allocators that are closer to average load, rather than peak load. See, for example, D.92-12-058, 47 CPUC 2d 438, 454.

[727] Cold year average daily flow allocates about 41.5% of the costs to core customers, rather than 67% under the existing cold year peak month. Exh. PG&E-02, Table 14-2, p. 14-9.

Docket No.: A.13-12-012 / I.14-06-016

Exhibit No.: CTAC - 6

Commissioner: Carla Peterman

ALJ: Amy C. Yip-Kikugawa

Date: February ___, 2015

011

Application 13-06-~~13~~:
PG&E Core Gas Capacity Planning Range Testimony

Application: 13-06-
(U 39 G)
Exhibit No.:
Date: June 13, 2013
Witness: Karen Lang

PACIFIC GAS AND ELECTRIC COMPANY

CORE GAS CAPACITY PLANNING RANGE

PREPARED TESTIMONY

PACIFIC GAS AND ELECTRIC COMPANY

CORE GAS CAPACITY PLANNING RANGE TESTIMONY

PACIFIC GAS AND ELECTRIC COMPANY
CORE GAS CAPACITY PLANNING RANGE TESTIMONY

TABLE OF CONTENTS

PACIFIC GAS AND ELECTRIC COMPANY
CORE GAS CAPACITY PLANNING RANGE TESTIMONY

A. Introduction

This chapter describes Pacific Gas and Electric Company's (PG&E) proposed revisions to its core interstate pipeline capacity planning ranges in compliance with Ordering Paragraph 3 of Decision 12-12-006. As stated in its application, PG&E proposes the following interstate capacity ranges for total core (referred to herein as "core") demand:[1]

- April – October: 85 percent-120 percent of forecast average annual daily core demand (or a forecast range of 688 thousands of decatherms (MDth)/day – 971 MDth/day at the California border for 2013-2023).
- November – March: 105 percent-120 percent of forecast average annual daily core demand (or a forecast range of 850 MDth/day – 971 MDth/day at the California border for 2013-2023).

The above ranges provide the flexibility required to reliably meet forecast core loads in the PG&E service territory using various combinations of firm pipeline and storage capacity as well as limited additional supplies, the use of which would vary depending upon the reliability, availability and economics of such products. Specifically, the ranges provide opportunities to reduce capacity costs during lower core demand periods, while recognizing the need for reliable firm capacity and supplies during higher core demand periods. PG&E's proposed capacity range is appropriate for both the level and seasonality of the total core load in PG&E's service territory as the average annual daily load volume for the core market varies greatly from the average daily load for any month. Furthermore, by specifying a sufficient capacity requirement, PG&E's proposed capacity ranges further the Commission's policies regarding reliability and long-term supply access.

This testimony first discusses historic and forecast future core gas demand. PG&E's proposed interstate capacity ranges are based in large measure on this data. This testimony next discusses the supply options available to meet core

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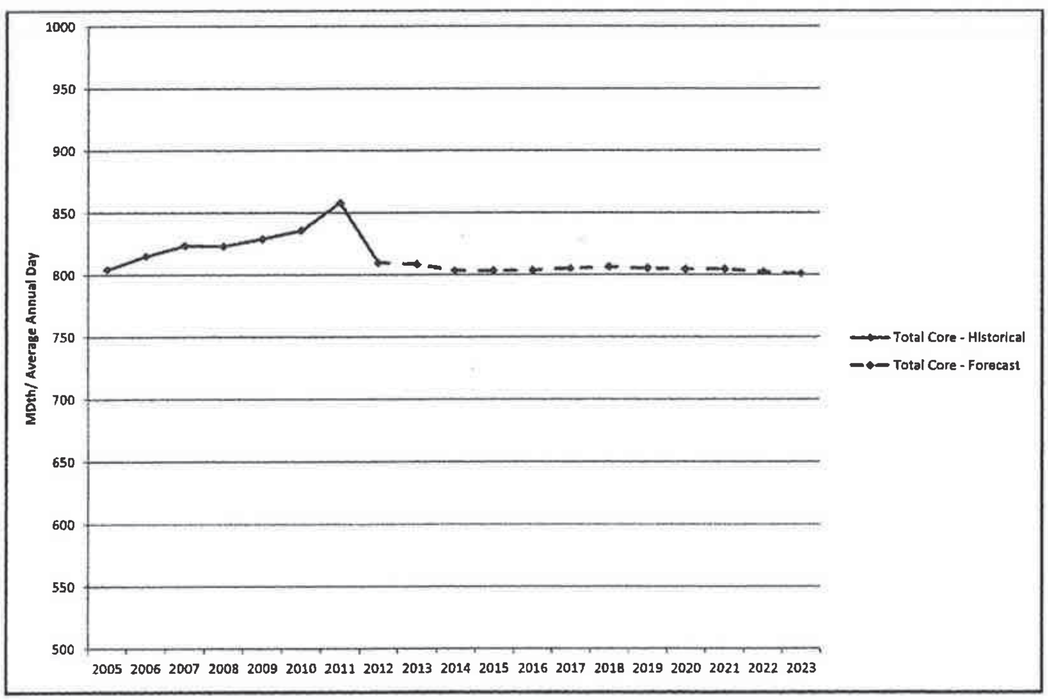
1 Total core demand refers to all core gas customers in the PG&E service territory including both customers who obtain natural gas supplies through PG&E's bundled service or using Core Transport Agents (CTA).

gas demand, how PG&E plans to meet core gas demand over the next 10 years, the adequacy of PG&E's proposed interstate capacity ranges, and, finally, the adequacy of interstate pipeline capacity to meet forecast core gas demand.

B. PG&E's Historical and Forecast Total Core Demand, 2005-2023

Total core demand includes natural gas usage of residential households, small and some large commercial customers, and natural gas refueling stations in PG&E's service area. As reflected in Figure 1, PG&E's actual total core average annual daily loads from 2005 to 2011 have ranged between 804-858 MDth/day (at the California border), with the higher loads due to cold winters, particularly in 2011.[2] From 2012 to 2023, average annual daily demands are forecast[3] to remain approximately constant at 809 MDth/day (at the California border) given average weather conditions.

FIGURE 1
PACIFIC GAS AND ELECTRIC COMPANY
TOTAL CORE AVERAGE ANNUAL DAILY LOAD: 2005-2023
(MDth/DAY AT CALIFORNIA BORDER)



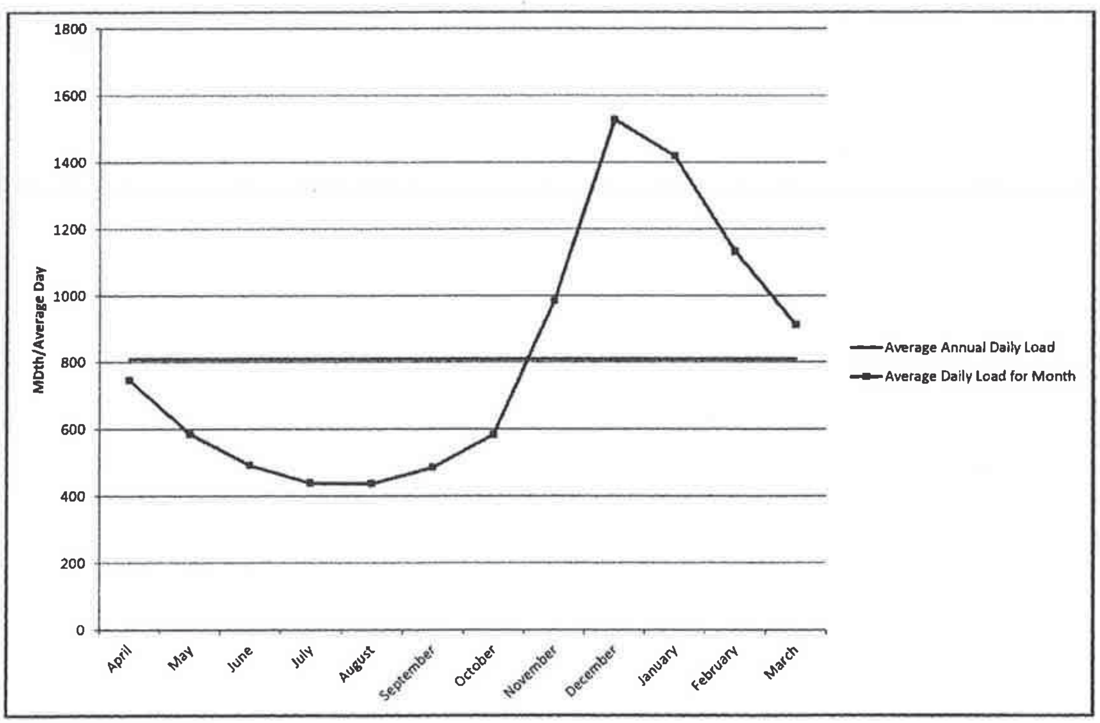
Data source: 2012 California Gas Report workpapers; loads converted to border volumes.

2 The total heating degree days for the calendar year 2011 closely match a 1-in-10 year return period.

3 2012 California Gas Report workpapers; loads converted to border volumes.

The average *annual* daily load volume for PG&E's total core market, however, varies greatly from the average daily load for any *month*. As shown in Figure 2, the projected average annual daily load volume of 809 MDth/day can be as much as 719 MDth/day less than the 1,528 MDth/day average daily load in December or about 372 MDth/day more than the average daily load of 437 MDth/day in August.[4] As is the case with the average annual daily load, the average monthly daily loads are expected to remain essentially the same over the 2013-2023 forecast period.[5]

FIGURE 2
PACIFIC GAS AND ELECTRIC COMPANY
PROJECTED MONTHLY AVERAGE TOTAL CORE LOAD PROFILE
(MDth/DAY AT CALIFORNIA BORDER)



Source: 2012 California Gas Report forecast with calendar-month detail, converted to border volumes. See Appendix A.

4 The residential portion of the core demand forecast is highly dependent upon temperatures, with the lowest demands expected in the summer months, and the highest demands during cold weather months.

5 Source: 2012 California Gas Report forecast with calendar-month detail. See Appendix A.

PG&E's proposed interstate capacity range of between 688 MDth/day and 971 MDth/day reflect this significant variation between the average *annual* daily load volume and the average daily load for any *month*. Importantly, and as discussed further herein, the proposed capacity ranges also account for core market storage capacity to meet seasonal core demand.

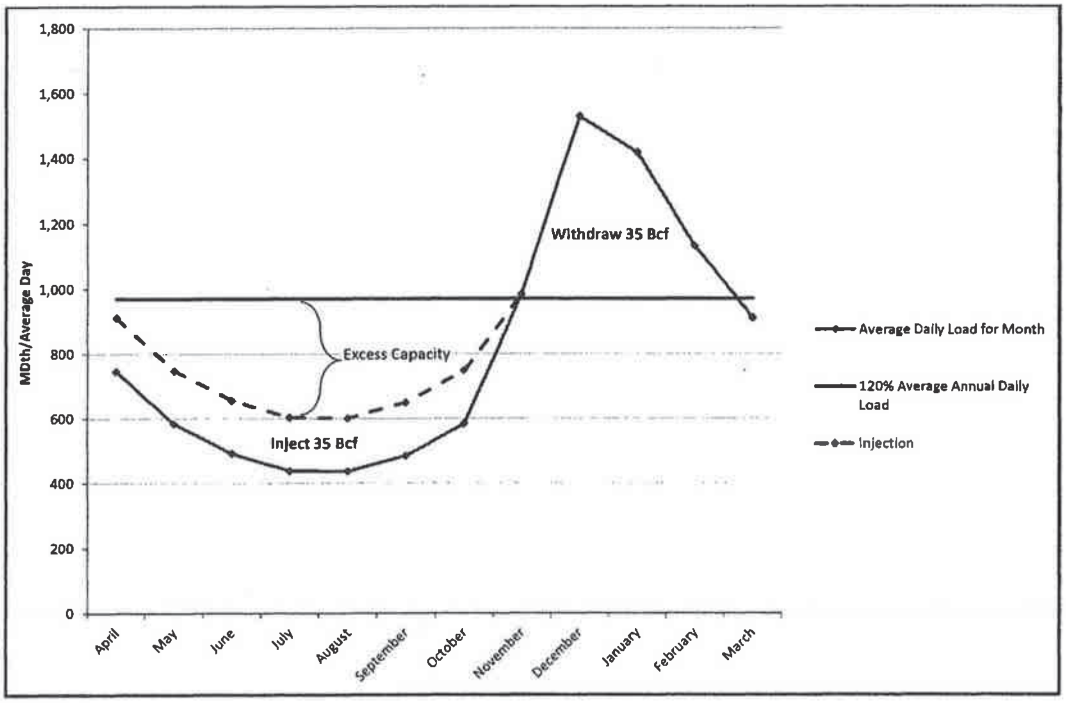
C. Supply Options to Meet Core Gas Demand

The proposed capacity range is based on the potential utilization of the following supply options: (1) annual constant-volume firm capacity contracts; (2) so-called "shaped" capacity contracts and seasonal capacity contracts; (3) additional storage capacity contracts; and (4) procurement of limited border and Citygate supplies. Each of these supply options is discussed briefly below in order to provide a framework for PG&E's plan to meet future core gas demand.

1. Annual Constant-Volume Firm Capacity Contracts

Annual constant-volume firm capacity commitments are one means of reliably supplying PG&E's core loads. As shown in Figure 3, approximately 120 percent of the average annual daily load of 809 MDth/day, or 971 MDth/day of firm capacity at the California border, is needed to serve average loads during November through March given PG&E's existing core market storage capacity of 35 billion cubic feet (Bcf) (34,978 MDth).

FIGURE 3
PACIFIC GAS AND ELECTRIC COMPANY
UTILIZATION WITH FIRM PIPELINE CAPACITY AT
120 PERCENT AVERAGE ANNUAL DAILY LOAD
(MDTH/DAY AT CALIFORNIA BORDER)



While annual constant contract volumes may sometimes be the only form of interstate capacity that pipeline companies are willing to offer, such contracts result in excess capacity during May through September. The costs associated with this excess capacity would be borne by core customers[6] if the associated reservation costs are not fully recovered through capacity release or point-to-point sales.[7]

2. Shaped Firm Capacity and/or Seasonal Capacity Contracts

The use of "shaped" capacity (i.e., annual contracts with varying monthly volumes) and seasonal capacity contracts (e.g., a contract with a one to

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6 For core customers who obtain gas supplies from PG&E, the current Core Procurement Incentive Mechanism effectively passes through all reservation costs to customers, with potential offsets from released capacity and point-to-point sales revenues.

For core customers who obtain gas supplies from CTAs, the costs of pipeline capacity reservation costs assigned but not utilized would logically also be fully recovered from customers less potential offsets from released capacity and point-to-point sales revenues.

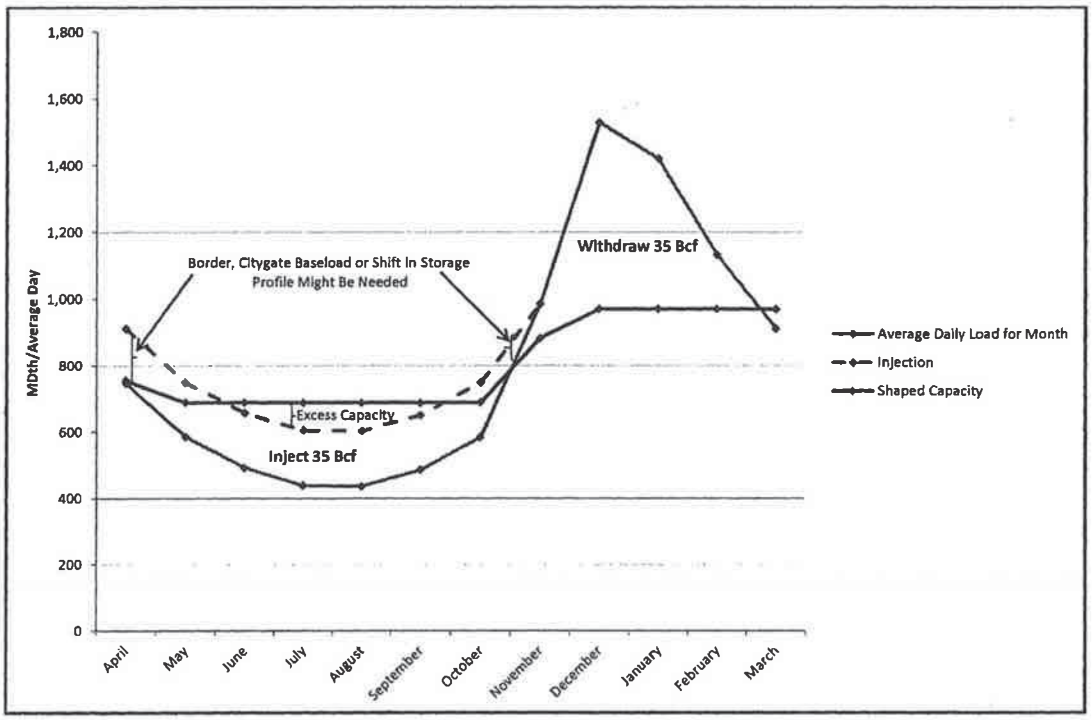
7 Point-to-point sales consist of buying supplies, transporting to a downstream delivery point and selling these supplies in order to capture the transport value on a given day.

five-month term) provide opportunities to build a capacity portfolio that more closely matches core load patterns, thereby increasing the utilization of the contracted firm pipeline capacity for core customer loads.

An example of employing both shaped firm capacity and existing storage capacity to increase utilization of firm pipeline capacity is shown in Figure 4. In this example, firm pipeline capacity is lowered to 85 percent of the average annual daily load (688 MDth/day) to minimize excess capacity during the months of June-September. During the high-load winter months, the total contract volume reaches 120 percent of the average annual daily load, commensurate with the loads and available storage for those months.

During the shoulder months of April, May and October, additional baseload supplies from PG&E Citygate, Topock and/or Malin may be needed with this shaped-capacity portfolio example. Since weather is typically mild and the total gas market loads are relatively low during these months, reliability concerns regarding supplies from these sources are relatively minor.

FIGURE 4
PACIFIC GAS AND ELECTRIC COMPANY
UTILIZATION WITH POSSIBLE SHAPED FIRM PIPELINE CAPACITY PROFILE
(MDth/DAY AT CALIFORNIA BORDER)



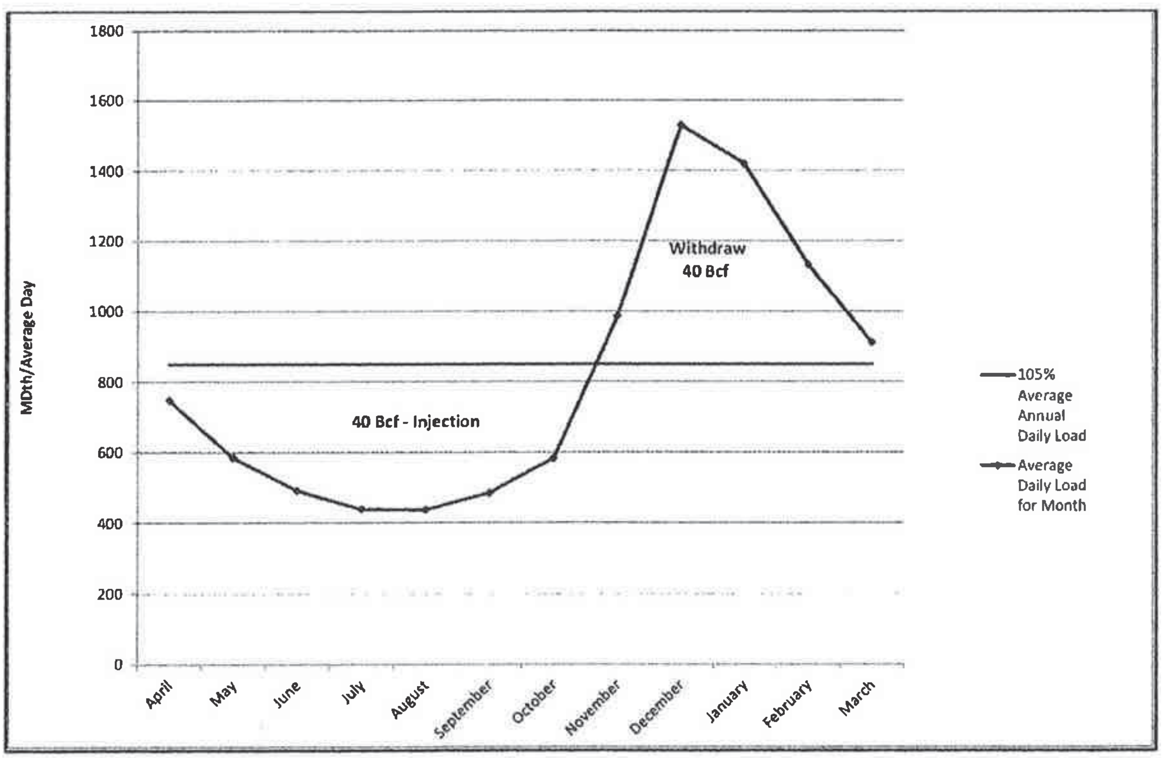
Historically, PG&E's Core Gas Supply contracted for interstate pipeline capacity with flat annual contract quantities. PG&E recently executed shaped contracts with southwest interstate pipelines that provide lower contract volumes in non-peak months and higher contract volumes during peak periods. PG&E has also entered into one to 5-month seasonal contracts to increase total interstate pipeline capacity during peak load periods.

There is no guarantee, however, that there will be future opportunities for PG&E to shape its contracts or obtain seasonal capacity contracts at competitive prices. Market conditions at the time of capacity acquisition and the competitive position of individual pipelines may contribute to the availability and price of capacity that can be shaped as well as to the availability and price of seasonal contracts.

3. Additional Storage

Another means of reducing excess pipeline capacity is to obtain a nearly constant volume of firm pipeline capacity close to the average annual daily load and then increase the contracted storage to both meet higher loads with withdrawal and increase pipeline capacity utilization with greater injection during lower-load months. One possible combination of increased storage and reduced firm capacity is 850 MDth/day of firm annual capacity (or 105 percent of the average annual daily load of 809 MDth/day) and 40 Bcf of storage inventory, as shown on Figure 5. Given supply diversity objectives and current contractual commitments, the option of procuring additional storage will be considered in the future.

FIGURE 5
PACIFIC GAS AND ELECTRIC COMPANY
STORAGE CAPACITY NEEDED FOR GREATER PIPELINE CAPACITY UTILIZATION AT 105 PERCENT ANNUAL AVERAGE DAILY LOAD
(MDth/DAY AT CALIFORNIA BORDER)



4. Border and Citygate Supplies

With PG&E's current core storage capacity,[8] additional 30-day (less than 100 MDth/day) and daily supplies are needed to meet higher loads in some months. Such supplies can be obtained from PG&E Citygate, or, depending upon core intrastate holdings or capacity availability, from Malin, or Topock. For planning purposes, PG&E recommends a limited reliance on PG&E Citygate supplies of up to 500 MDth/day (30-day plus daily supplies) on the highest load days to ensure reliability and price stability. The rationale for this limit is discussed further in Section D.

D. PG&E's Plan to Meet Core Gas Demand, 2013–2023

Over the next decade, PG&E proposes to meet core gas demand through the use of: (1) interstate pipeline capacity contracts that reflect PG&E's proposed capacity ranges; (2) existing and, if available and economic, additional storage capacity contracts; and (3) a limited volume of additional baseload and daily supplies, as needed, mainly from the PG&E Citygate market.

1. Interstate Pipeline Capacity Contracts

PG&E's core customers have benefited from long term contractual relationships with interstate pipelines serving northern California. PG&E's firm transportation contracts have provided direct access to prolific supply basins while enhancing gas-on-gas and pipeline-to-pipeline competition. Interstate pipelines serving northern and central California include: El Paso Natural Gas Company (El Paso), Gas Transmission Northwest, Kern River Gas Transmission, Ruby Pipeline (Ruby), and Transwestern Pipeline Company.

The California Public Utilities Commission (CPUC or Commission) has actively promoted policies encouraging the utilities to commit for firm interstate capacity on these pipelines. Since the Energy Crisis of 2000-2001, the Commission has acted to ensure that California customers retain unfettered access to the major western natural gas production areas.

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8 Total core market in PG&E service territory (i.e., Core Gas Supply and all other Core Transport Agents) is assigned 33,478 MDth of firm storage capacity from PG&E's Gas System Operations; and Core Gas Supply has an additional 1,500 MDth contracted from the Lodi Gas Storage.

- In the El Paso Order Instituting Rulemaking (OIR) (D.02-07-037), the Commission ordered the gas utilities to acquire El Paso capacity that would otherwise be controlled by shippers serving customers east of California.
- In Decision 04-09-022, the Phase I decision in the Natural Gas OIR, the Commission established general policies acknowledging the important role of interstate pipeline capacity in the utilities' gas supply portfolios, and determined that gas utilities should hold a diverse portfolio of pipeline capacity across multiple supply basins to ensure adequate supplies for core gas customers.[9] That same order established mandatory ranges for the amount of pipeline capacity that should be held by each utility.
- Finally, in Decision 08-11-032, the decision approving PG&E's Ruby Pipeline gas transportation arrangements, the Commission reiterated its policy objectives of utilities maintaining diverse supply portfolios, and its role of ensuring supply adequacy and reliability, including the statement "as regulators, we have a responsibility for ensuring that California has access to adequate supplies of natural gas."[10]

PG&E's proposed interstate capacity ranges further the Commission's policies by requiring PG&E to obtain sufficient interstate pipeline capacity to ensure reliability and long-term gas supply access. Specifically, as discussed, PG&E proposes the following interstate pipeline capacity ranges for total core load, as illustrated in Figure 6:

- April – October: 85 percent-120 percent of forecast average annual daily core demand.
- November – March: 105 percent-120 percent of forecast average annual daily core demand.

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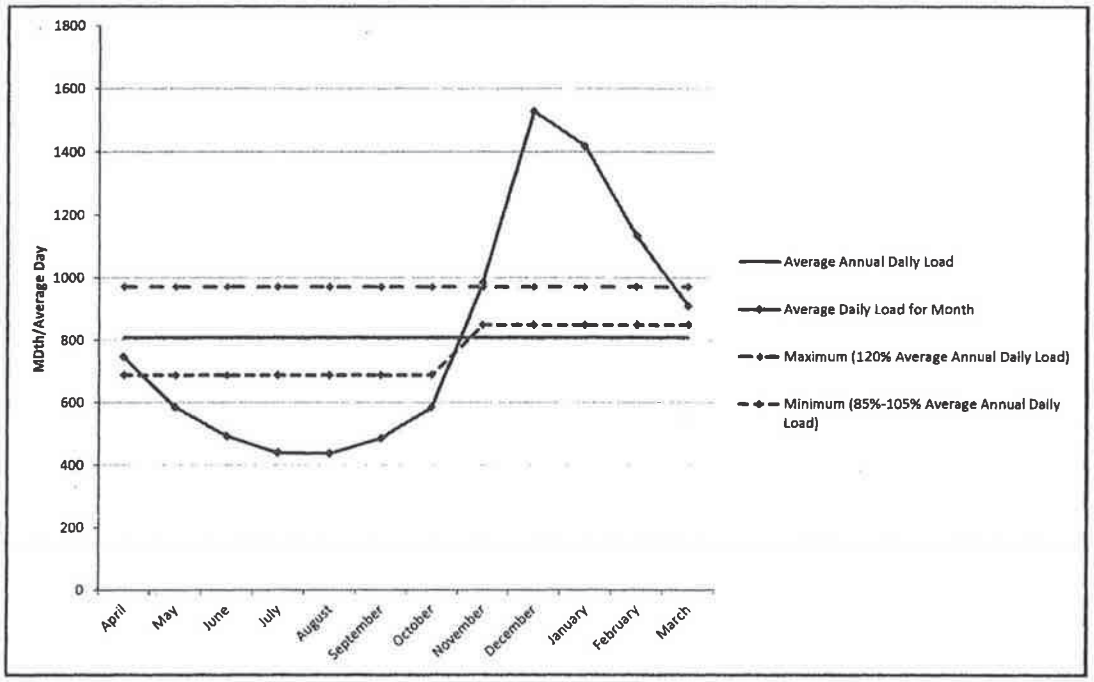
9 D.04-09-022, Findings of Fact 1.

10 D.08-11-032, p. 17.

FIGURE 6
PACIFIC GAS AND ELECTRIC COMPANY
PROPOSED FIRM INTERSTATE CAPACITY RANGE USING
PROJECTED AVERAGE ANNUAL DAILY LOAD FOR 2013-2023
(MDth/DAY AT CALIFORNIA BORDER)



The higher percentage, 120 percent of average annual daily core load, allows for sufficient capacity in peak winter months. The continuation of the 120 percent upper bound in the summer allows for times when only constant monthly volumes are offered in annual pipeline capacity contracts and additional storage capacity is not economically and/or consistently available (see Section C.1).

The 105 percent lower winter bound provides sufficient reliability should PG&E be able to acquire enough additional storage capacity at terms more favorable (i.e., regarding reliability and economics) than comparable supplies provided by firm pipeline capacity (see Section C.3). The 85 percent lower summer bound allows for sufficient pipeline capacity to meet summer loads and current storage injection requirements. This lower bound would be relevant if PG&E were able to obtain a broad range of monthly volumes within annual firm capacity contracts (see Section C.2). Notably, the proposed lower capacity limit of 85 percent of average annual daily core load for April-October is 5 percent lower than the current summer capacity limit for Southern California Gas Company (SoCalGas). Due to the greater seasonality of PG&E's loads and less contracted storage capacity,[11] a slightly lower capacity limit would result in greater pipeline capacity utilization and provide sufficient supply reliability when seasonal storage or pipeline capacity or other peaking supply products are available.

PG&E proposes to continue to:

- Stagger both the length and the termination date of capacity contracts to provide flexibility to match loads and to complement other capacity commitments.
- Maintain access to different supply basin markets to ensure reliability and provide a portfolio approach for price stability.

PG&E believes that this diversified contracting approach will enable it to make contracting adjustments in response to market constraints as well as to take advantage of lower capacity costs when available.

PG&E further proposes that:

- The capacity volumes associated with the capacity ranges be updated and submitted once every two years using the forecast loads published in the California Gas Report (CGR). This will help ensure that PG&E's core interstate pipeline capacity holdings remain reflective of current and forecast total core demand on a going-forward basis.
- PG&E submit its updated core capacity range volumes to the Commission using an advice letter filing so as to allow PG&E to take appropriate market action in a timely manner.
- PG&E adjust its capacity holdings by April of the year following the latest CGR (typically issued in July) so as to allow sufficient time for contract

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11 Using the forecast monthly 2013 total core loads from the 2012 California Gas Report workpapers, the range of the minimum to maximum average daily load per month at the burnertip is 797 MDth/day for SoCalGas(using MDth = 1.02 x MMcf) whereas this same range is 887 MDth/day for PG&E. For SoCalGas, the maximum deviation from the average annual daily load of 952 MDth/d is + 537 MDth/d in December. For PG&E, the maximum deviation from the average annual daily load of 781 MDth/d is + 604 in January. Notably, SoCalGas' core storage inventory is 83 Bcf (SoCalGas' Advice Letter No. 4499, dated May 29, 2013), more than double the 35 Bcf of current storage inventory within PG&E's core portfolio.

http://www.socalgas.com/regulatory/documents/cgr/REDACTED%20SoCalGas%207%2025%2012.pdf, p. 11, and 2012 California Gas Report Workpapers, Pacific Gas and Electric Company, July 2012, II.D. Average Demand Year Forecast Tables, p. 53.

adjustments, as does SoCalGas. PG&E will calculate the capacity ranges as an equivalent border quantity[12] reflecting appropriate shrinkage rates on PG&E's transmission and distribution pipeline systems.

2. Limited Reliance on PG&E Citygate Supplies for Core Market Planning

For PG&E's core natural gas purchases, PG&E is proposing a 500 MDth/day planning limit for PG&E Citygate supplies based on an estimate of the reliance on daily supplies at PG&E Citygate in recent years during cold weather conditions. In light of the objectives of Decision 04-09-022, reliance on PG&E Citygate supplies should be limited such that it does not impact the sufficiency of interstate and intrastate pipeline capacity available to serve California.[13] Specifically, firm capacity commitments contribute to the viability of maintaining pipeline capacity to California and the associated access to basin supplies. Purchases at PG&E Citygate do not involve the explicit ownership and control of firm rights from the supply basin by the core market. Thus, PG&E is proposing to limit PG&E Citygate purchases and maintain firm capacity commitments for the majority of core load volumes. Given the current excess of interstate pipeline and storage capacity in northern California (see Section F), the recommended limited PG&E Citygate supply reliance for planning is not likely to impact the sufficiency of available capacity. Further, the sufficiency of available capacity is also likely to provide for the continued availability of limited PG&E Citygate supplies.

The current recommended planning limit for utilization of PG&E daily Citygate supplies is based on estimates of:

- Demand for daily supplies on a cold winter day by customer class (core, electric generation and industrial). The demand for daily supplies was

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12 PG&E requests that future references to the volume quantities of the capacity ranges be specified as to whether they are border, Citygate or burnertip volumes to eliminate confusion and insure adherence to any future revised capacity requirement.

13 D.04-09-022, p. 5. "In order to ensure reliable, long-term natural gas supplies to California at reasonable rates, it was determined that the Commission must make certain decisions in 2004 with regard to the California natural gas utilities that the Commission regulates, so that: (1) increased demand reduction efforts (*e.g.*, energy efficiency and renewable energy programs) help moderate the potential supply imbalance in the future; (2) sufficient firm interstate and intrastate pipeline capacity will be available to serve California;.."

based on the residual of a) 1-in-10 year cold winter day demands for the core, electric generation and industrial customer classes; and b) estimated monthly supply and storage usage levels for each customer class.

- Recent reliance on such supplies during high load winter days. The total daily supply reliance on a cold winter day was estimated using the difference between the median maximum and average total daily Citygate supplies during recent winter months. Further details on this estimate are provided in Appendix B.

E. Adequacy of PG&E's Proposed Interstate Capacity Ranges

PG&E utilized a model simulation, the Core Gas Asset Model (CGAM), to verify the adequacy of the interstate capacity ranges proposed to meet projected total core demand. The adequacy was assessed by determining if the available supplies for the scenarios presented in Figures 3, 4 and 5, above, were sufficient to supply core loads and injection requirements throughout the year while not exceeding the planning limit of 500 MDth of PG&E Citygate supplies on any given day.

Specifically, CGAM determines the daily load variability from projected monthly load volumes, and then determines the adequacy of the ranges by assessing the supply asset scenarios to meet the forecast daily loads through 2023. Further details regarding the CGAM structure are provided in Appendix C.

As expected, the CGAM results presented in Figure 7 show that the interstate pipeline capacity utilization is greater when the monthly capacity is closest to the load in that month. The CGAM's reliance on PG&E Citygate was limited to no more than 500 MDth/day and was not exceeded in any of the scenarios, even on a January high load day.[14]

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[14] The CGAM will use additional PG&E Citygate supplies if no other supplies, including storage, are available.

FIGURE 7
PACIFIC GAS AND ELECTRIC COMPANY
CGAM RESULTS FORECAST SUFFICIENCY OF INTERSTATE PIPELINE CAPACITY TO MEET PG&E'S CORE GAS LOADS, 2013-2023

		Interstate Pipeline Capacity Utilization	PG&E Citygate Supply Purchases MDth/D		
Alternative	**January 2017**		Average 30-Day	Average Daily	95% High Load Daily
1	120% Avg. Annual Daily Load	98%	47	74	453
2	Shaped Capacity	98%	47	74	453
3	105% Avg. Annual Daily Ld + Addtnl Storage	98%	79	75	422
Alternative	**July 2017**				
1	120% Avg. Annual Daily Load	63%	0		
2	Shaped Capacity	88%	0		
3	105% Avg. Annual Daily Ld + Addtnl Storage	76%	0		
Alternative	**Annual**				
1	120% Avg. Annual Daily Load	83%	21		
2	Shaped Capacity	94%	42		
3	105% Avg. Annual Daily Ld + Addtnl Storage	90%	46		

F. Forecast Sufficiency of Interstate Pipeline Capacity to Meet PG&E's Core Gas Loads, 2013-2023

PG&E believes that there is sufficient interstate pipeline capacity to meet the forecast core gas loads from 2013-2023 because the current interstate pipeline capacity connected to California, 10.5 Bcf/d,[15] is far greater than both the projected state peak load of 9.4 Bcf/d[16] and annual average loads of 6.1 Bcf.[17]

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[15] http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/StatetoState.xls)

2.4 Bcf/day of interstate pipeline capacity is connected to Oregon (Source: http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/StatetoState.xls)

1.8 Bcf/day of interstate pipeline capacity is connected to Nevada (Source: http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/StatetoState.xls)

5.7 Bcf/day of interstate pipeline capacity is connected to Arizona (Source: http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/StatetoState.xls)

0.6 Bcf/day of interstate pipeline capacity is connected to Mexico (Source: http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/StatetoState.xls)

[16] California Gas Report 2012, p. 51: Northern California's Winter Peak Day Demand is 4.4 Bcf/day; California Gas Report 2012, p. 99: Southern California's Winter Peak Day Demand is 5.0 Bcf/day.

[17] 2012 California Gas Report, p. 17.

- Note that existing pipeline capacity could be reduced through conversions to oil, de-rating, abandonment, or re-directed to serve new non-California markets. However, given the amount of available interstate capacity relative to projected state-wide demands and the need for federal review and approval before such reductions could take effect, interstate capacity should be sufficient to meet total state natural gas loads through 2023 even if some capacity reductions were to occur.
- From 2012-2030, California natural gas demand, is expected to decrease at a rate of -0.25 percent per year.[18]
- Commission policy requires sufficient firm capacity to be held to meet total core loads, thereby maintaining pipeline service and supply access to California.

G. Summary and Recommendation

PG&E recommends that the Commission adopt:

1. The following interstate capacity ranges for PG&E's total core demand:
    - April – October: 85 percent-120 percent of forecast average annual daily core demand (or a forecast range of 688 MDth/day – 971 MDth/day for 2013-2023).
    - November – March: 105 percent-120 percent of forecast average annual daily core demand (or a forecast range of 850 MDth/day – 971 MDth/day for 2013-2023).
2. An update procedure for the volumes associated with the capacity ranges that consists of:
    - Re-calculating the volumes associated with the ranges once every two years using the forecast loads published in the CGR, submitted in an advice letter filing.
    - Adjusting the capacity holdings by April of the year following the latest CGR (typically issued in July).

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18 2012 California Gas Report, p. 7.